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R. L. Capone (Science Applications) and L. G. Jones (AEERL)

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16. ABSTRACT The paper discusses the development of the Advanced Utility Simulation Model (AUSM), developed for the National Acid Precipitation Assessment Program (NAPAP), to forecast air emissions of pollutants from electric utilities. AUSM integrates generating unit engineering detail with dynamic strategic decisions made by utility planners and coal miners. Decisions about capacity additions and emissions control strategies for one unit, state, and year influence (and are influenced by) decisions made for other units, states, and years. Emissions control economics are controlled by unit-specific factors and by market factors. Designed as a cost-minimization model, AUSM integrates decisions about each unit with decisions about other units through competition for coal, interstate electricity transmission, intrastate system dispatch, and power pool, state, and unit-level emissions limits.

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DEVELOPMENT OF THE ADVANCED UTILITY SIMULATION MODEL

by:

Ronald L. Capone
Science Applications International Corporation
Modeling and Analysis Division
1710 Goodridge Drive
McLean, VA 22102

and

Larry G. Jones
Air and Energy Engineering Research Laboratory
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

The Advanced Utility Simulation Model (AUSM) was developed by the U.S. Environmental Protection Agency (EPA) under the auspices of the National Acid Precipitation Assessment Program (NAPAP) to forecast air emissions of pollutants from electric utilities. AUSM integrates generating unit engineering detail with dynamic strategic decisions made by utility planners and coal miners. Decisions about capacity additions and emissions control strategies for one unit, state, and year influence and are influenced by decisions made for other units, states, and years.

Emissions control economics are controlled by unit-specific factors and by market factors. Designed as a cost-minimization model, AUSM integrates decisions about each unit with decisions about other units through competition for coal, interstate electricity transmission, intrastate system dispatch, and power pool, state, and unit-level emissions limits.

Emissions control cost for one electric generating unit acting alone depends on the cost of installing and operating control equipment and can be calculated from boiler and coal attributes. But, if a new emissions control policy is established, few units can act completely alone. Control costs at one unit will influence and be influenced by control strategy decisions made at other units. Utility planners must and do consider these interactions along with unit level factors. So, evaluating results and impacts of a national emissions abatement policy requires a tool which preserves unit level engineering detail while simulating the interactive decisions of high level planners. The Advanced Utility Simulation Model (AUSM) was devised to fill the need for such a model.

AUSM was developed by the U.S. Environmental Protection Agency (EPA) under the auspices of the National Acid Precipitation Assessment Program (NAPAP). Work on the model was begun by the Universities Research Group on Energy (URGE) under cooperative agreements CR808514 and CR809461. URGE delivered a partial version in November 1984. Science Applications International Corporation (SAIC) completed AUSM in 1986 and has continued with testing and applications up to the present.

THE ARCHITECTURE OF AUSM

AUSM can combine strategic considerations with unit level detail because it has two components, as shown in Figure 1. The National Loop, shown in Figure 2, calculates long term strategy by simultaneously evaluating dispatch, capacity addition, fuel, mining, interstate transfer, and emissions control decisions for all years in each state in each of 13 power pools. The State Model, shown in Figure 3, simulates demand, capacity planning, compliance with emissions regulation, dispatch, emissions, and financial operations at the generating unit level for each year in each state. Simultaneity in the national loop ensures that each unit influences and is influenced by every other unit and that decisions about the present include decisions about the future. Simulation in the state model ensures use of unit level detail and mimics the results of running a utility from one year to the next.

The National Loop

The national loop simulates coal-electric utility market equilibrium by iteratively calculating coal demand for each of 33 possible coals, calculating new delivered coal prices from demand, and recalculating demand from the new coal prices until prices converge. Demand is calculated by solving 13 linear programs, 1 for each power pool, which minimize total system cost over a 60 year period subject to engineering and policy constraints. Delivered coal price is calculated by solving 18 linear programs, 1 for each rank and 10 year time slice from 1990 to 2040, which find the least cost allocation of supply to demand.

Market behavior is simulated by first calculating derived coal demand, using resulting demand data to find coal price, and recalculating coal demand. Each calculation cycle, from price to demand to price, constitutes one iteration of the national loop. A test for equilibrium is made at the end of each cycle.

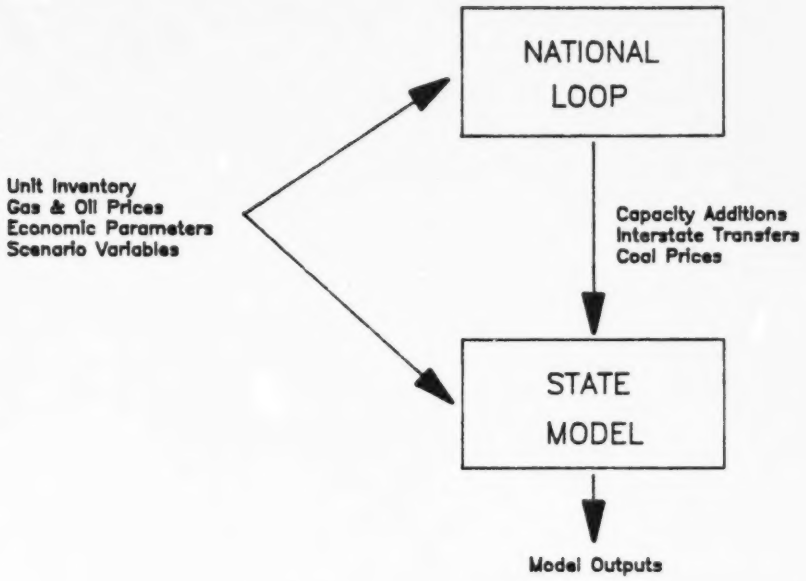


FIGURE 1 AUSM

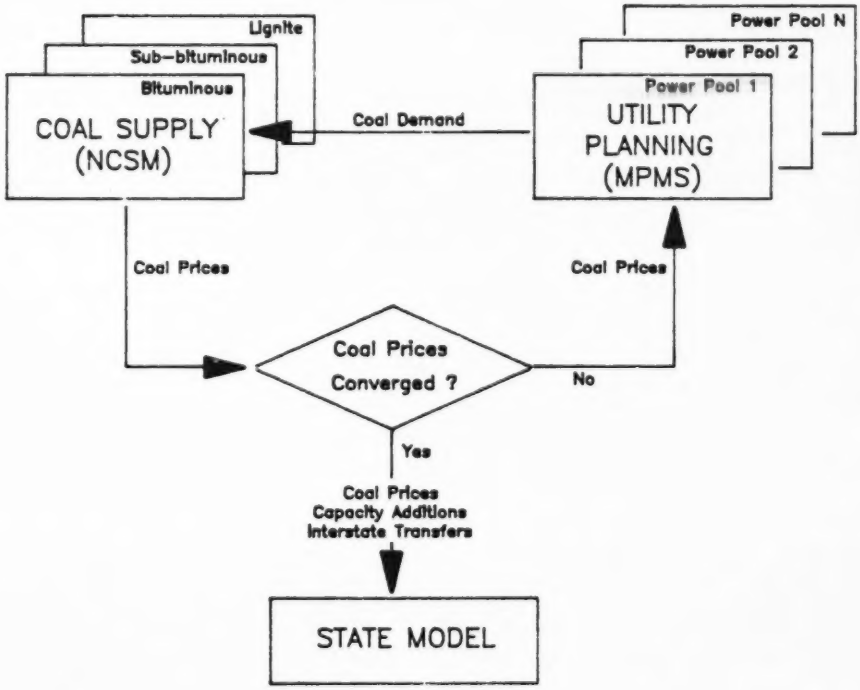


FIGURE 2 THE NATIONAL LOOP

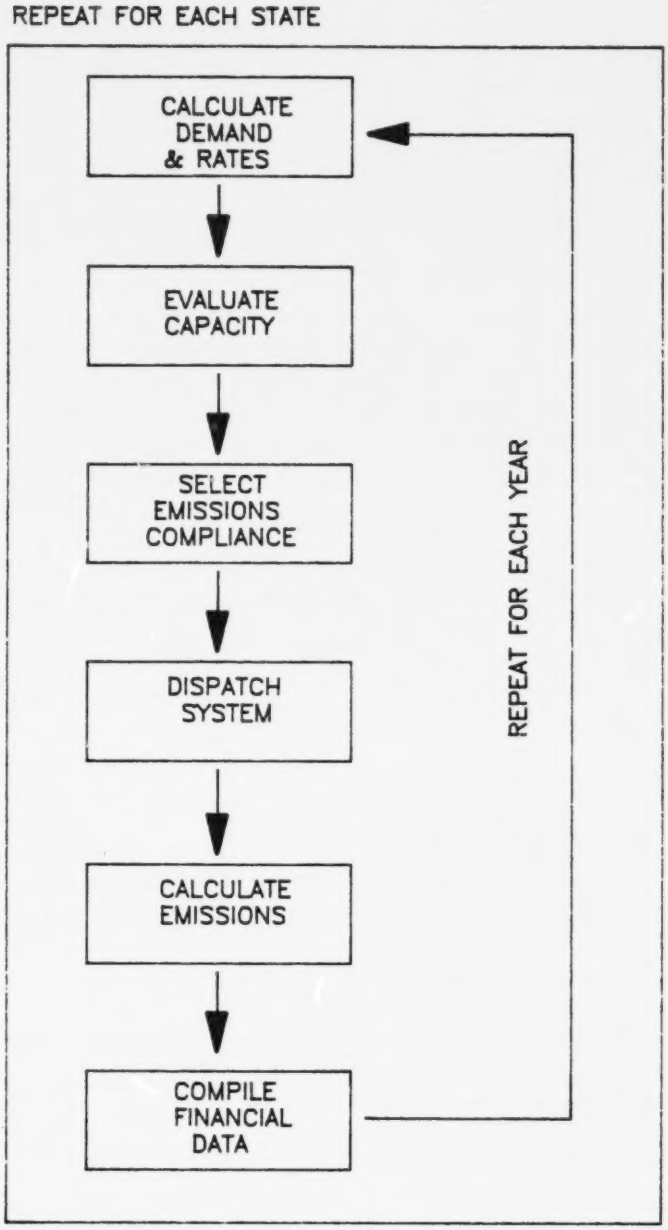


FIGURE 3 THE STATE MODEL

Equilibrium is signalled by price convergence, where the definition of "convergence" is user-defined. Users can select absolute convergence (+/- $x/MMBtu), relative convergence (+/- x% difference), a combination of the two, and one of several weighting schemes. Prices from each iteration of the national loop are compared with prices from the previous iteration using the convergence criteria. When the criteria have been met, iteration ends and coal prices, capacity additions, interstate transfers, and the prices charged for exported electricity are passed to the state model.

The Multi-Period, Multi-State Module:

Coal demand, capacity additions, and interstate transfers are calculated in the Multi-Period, Multi-State (MPMS) module. MPMS executes for each power pool region independently, where regions consist of one or more states. The geographic makeup of each region is user-definable if regions include no more than seven states. Current practice is to use 13 regions which correspond to the North American Electric Reliability Council (NERC) regions with some adjustment to make regions coincide with state boundaries.

MPMS minimizes the present value of capital, non-fuel O&M, fuel, and transmission costs from 1980 through 2040 subject to constraints. Capital costs include generating and emissions control equipment additions. (The existing equipment is treated as a sunk cost.) Fuels include coal, high and low sulfur residual fuel oil, distillate, gas, and nuclear fuel. Fuel cost is calculated from price and consumption, which is calculated from heat rate and hours of operation. Non-fuel O&M, denominated in $/MW, is added to the cost of capital as a computational convenience. Transmission costs are calculated from a user-specified constant price, expressed in $/kWh/mile, and the amount of electricity transferred between pairs of states, which includes losses.

The current version of MPMS includes several kinds of end effects: replacement of capacity in place in 2040, capital additions required by growth assumed to occur after 2040, and operation of both. Life times, heat rates, fuel cost, and O&M expense are included in the end effects, as are escalation and discounting.

Several kinds of constraints are used in MPMS: demand must be met for each of five segments of a state-specific, annual load duration curve whose shape is determined by peak demand, a base to peak load ratio, system load factor, and whether the state is summer or winter peaking. (Load duration curves change over time by changing the system load factor.) A minimum reserve margin must be maintained, and this is calculated as a fraction (typically 20 percent) of peak load. No unit may be operated beyond its design capacity and availability, where capacity is adjusted for expected forced outage.

Several kinds of emissions regulations are provided for: new units must comply with revised new source performance standards (RNSPS). Units which are already in the inventory or which are firm announced units must comply with NSPS or individual state emission limitations imposed by State Implementation Plans (SIPs), whichever applies. Additionally, users may impose either region-wide or

state-specific limits on SO_2, NO_x, or particulates, and these limits may vary over time.

Finally, users have the option to apply steering constraints which limit the proportion of capacity represented by each generating technology. These have been provided for use in simulating phenomena like nuclear moratoria and to constrain MPMS results as required by special kinds of analyses. Little use of such constraints has been made in AUSM applications.

Interstate transmission is calculated for one-way transfers between each pair of states for each load duration curve segment for each time period. So, it is possible for state A to sell base load electricity to state B and buy peaking electricity from B. The choice is made on the basis of cost and depends on economic advantages offered by each state in the region.

Economic inputs include capital and non-fuel O&M costs for each kind of generating technology, emissions control cost, transmission cost, coal prices (from the coal supply module), the prices of other fuels, and discount rates. Costs can vary among the states in a region.

Initial (1980) generating and emissions control capacity is calculated from the NAPAP unit inventory National Utility Reference File (NURF). Planned additions, scheduled for completion after 1980, are also derived from NURF. MPMS capacity endowment begins with 1980 capacity and this is adjusted to reflect planned additions and retirements, which are calculated from NURF or from scenario-dependent unit lifetimes.

National Coal Supply Module:

Coal price is calculated by the National Coal Supply Module (NCSM) from data on coal reserves, mining cost assumptions, coal cleaning cost, and transportation cost. Prices are calculated for each of 11 sulfur categories for each of 3 ranks (bituminous, sub-bituminous, and lignite). Mining cost is calculated by the Resource Allocation and Mine Costing (RAMC) Model, and reserves, which are based on the Energy Information Administration's (EIA's) Demonstrated Reserve Base (DRB), are adjusted for depletion.

NCSM allocates supply from 35 supply regions to demands from the 48 contiguous states so as to minimize cost. Cost, in turn, consists of mining, cleaning, and transportation. Price is calculated as the cost incurred by the marginal supplier to each demand region. Because costs increase as a function of quantity demanded, low cost mines enjoy rents equal to the difference of their cost and delivered price.

Free market pricing adjustments are made to ensure that delivered price within a state never rises as sulfur content rises. In a freely operating market, the difference between the price of two coals of different sulfur content will be no less than the cost of scrubbing flue gas from the dirtier coal. In other words, if coal A has less sulfur than coal B, coal A will sell for more. However, the price of coal B cannot be higher than the price of A minus the cost of scrubbing or utilities would prefer coal A because the combined cost of buying and scrubbing coal B would be larger. Utilities will be indifferent between buying A or B if the

price of A just equals the price of B plus the cost of scrubbing B. (In fact, utilities may also insist on a somewhat higher differential to allow for risk, scrubber aversion, etc. However, the size of such a premium has never been adequately evaluated.) If the price of A is higher, utilities will prefer B because operating costs will be lower.

The delivered price of coal B, as computed by NCSM, may be higher than coal A, forcing the price of the dirtier coal above the price of the cleaner coal. Suppliers, in a model's world, would never sell A for less than B because utilities are willing to pay more for A than B providing the difference does not exceed the differential scrubbing cost. In this situation, suppliers will raise the price of A to the indifference price, which will ensure that the delivered price of coal within a state does not increase as sulfur increases.

Price differences between coals of different sulfur contents can be higher than the scrubbing differential because utilities in each state compete with utilities in other states for available supply. The national coal market, as modelled by AUSM, consists of 35 supply regions producing 33 different coals among them and 48 demand regions. Suppliers compete with each other to sell coal, and states bid against one another to buy coals needed for existing and planned units. Equilibrium coal prices reflect the dynamics of this complex market.

Data Passed to the State Model:

After the national loop reaches equilibrium, the following information is passed to the state model: generating and control capacity additions, coal prices, interstate transfers, load duration curves which must be met by in-state resources, and prices charged for exported electricity. A variety of reports are available from the national loop, allowing it to run as a stand-alone model, but the more normal course of events is to pass control to the state model.

The State Model

The state model, the first version of which was completed by URGE, uses national loop data to simulate utility operation for the period 1980 - 2010. Utility operation is simulated by sequentially executing six modules for each year for each state. Figure 3 depicts the state model. Two modules, the control program and the report writer, are not shown. Their functions are transparent.

Execution begins with DEMAND, which calculates sales to end users, intrastate transmission and distribution losses, electricity prices (based on revenue requirement), and forecasts generation required in the future. Although there is an endogenous mode in which demand is forecast from price information (calculated for previous years), the more normal approach is to take demand growth as exogenous.

PLAN uses information from DEMAND, the inventory of existing units, and the inventory of scheduled additions to determine whether sufficient capacity

does/will exist. If not, construction schedules can be advanced. (Alternatively, PLAN can build new units on its own -- although this rarely occurs.) Where too much capacity would exist if additions are completed on schedule, construction can be deferred. A number of parameters moderate PLAN to ensure user control. For example, construction is not normally deferred if more than 50 percent of a generating unit has been completed.

A typical construction schedule is provided for each generating technology showing how many years are required and the fraction of total cost incurred in each year. Annual construction expenses are passed to FINANCE (discussed below) for inclusion in financial simulations.

COMPLY has two important functions: it determines how an individual unit will comply with emissions regulation for new units based on established federal standards and it selects a compliance strategy for existing units whose emission limit changes for any reason. Compliance strategy consists of control device retrofit to existing units, inclusion of a control devise on new units, and coal selection for both. All decisions are made on the basis of lowest present value of life cycle cost.

Existing units must, for most units, comply with a SIP emissions standard tabulated in the unit inventory. Information on standards consists of an emissions rate and a date by which that rate must be achieved. The present value of total cost is determined for each combination of coal and control devices, where the list of devices includes wet and dry scrubbers, Limestone Injection Multistage Burners (LIMB), and low NO_x burners. This list may be augmented very easily. The cost computation includes provision for a retrofit factor specific to each control technology. Input data contain information on the capital cost of controls plus O&M expenses like reagent cost. Future versions of COMPLY will also include provision for unit-specific retrofit factors.

SIP limits in the unit inventory may be modified using a special routine to represent any number of policy initiatives. For example, a recently proposed emission reduction regulation would limit SO_2 emissions to 520 ng/J (1.2 lb/MMBtu) for each unit on the later of 1995 or its 30th anniversary. Modelling this policy required SIP modification to calculate the compliance date and insertion of the 520 ng/J limit.

DISPATCH consists of a linear program which dispatches individual units to meet load by load duration curve segments at the lowest cost while honoring constraints on unit size, availability, reliability, and emissions limits. Individual unit data on heat rate, fuel, reliability, availability, emissions rates, and non-fuel O&M expense are used. Heat rates depend on their 1980 value for existing and announced units, on their scenario-specified value for units forecast by AUSM, and an age-dependent increase. (The current rate is 0.25 percent/yr.) Fuel prices depend on the price paid in 1980 for existing units for which COMPLY did not change fuels and on prices for coal provided by the national loop or as exogenous input for other fuels.

Emissions constraints include state-specific limits on SO_2, NO_x, and particulates. The constraint set is

currently being modified to allow time dependent variation for all species. This modification will allow modelling of emission control policies in which increasingly stringent limits are placed on each state.

The effect of emissions limit constraints is to simulate trading among units within a state. The effect of the linear program taken as a whole is to cause units to be dispatched in the most economic order given the shape of the load duration curve and the cost of running each unit.

IMPACTS uses information about individual unit emissions rates, unit sizes, and capacity factors from DISPATCH to calculate emissions. Air emissions include SO_2, NO_x, and particulates. Additionally, IMPACTS calculates ash and scrubber sludge production and figures water use.

FINANCE uses cost information gathered from upstream modules to prepare the three basic financial statements (income statement, balance sheet, and sources/uses of funds statement), calculate the rate base, and calculate the revenue requirement. The revenue requirement is passed to DEMAND, which calculates electricity prices.

Input data include information about the financial position of the hypothetical utility serving each state. State-specific costs of capital data are used to find the cost of new financing. A recent addition to FINANCE is the ability to calculate the cost of debt as a function of financial position. This routine provides that the cost of new debt increases as the financial position deteriorates.

Revenue requirement includes depreciation, fuel cost, O&M expense, financing cost (interest plus dividends), and taxes. Tax regulations have been updated to include all regulations from 1980 to the present. A number of detailed reports are available from which to perform detailed economic analyses.

Finally, FINANCE output for each year is fed back to DEMAND for the next year. DEMAND recalculates electricity prices for each end use sector. If DEMAND is run in endogenous mode, electricity sales vary as a function of price. Exogenous mode simply uses user-defined growth rates for sales. In both cases, prices and sales are multiplied to calculate revenues, which pass to FINANCE where they are incorporated into the income statement.

The state model is equipped with a set of standard, formatted reports covering all aspects of the simulation. Reports may be selected by the user from a menu. Optional trace reports are provided with each module to allow extreme detail, frequently at the generating unit level. SAIC has further enhanced reporting capability by providing a relational database containing unit-specific data supporting ad hoc inquiries.

TESTING, CALIBRATION, AND DOCUMENTATION

AUSM has been subjected to a number of univariate sensitivity tests, compared with results from ICF, Inc.'s Coal and Electric Utility Model (CEUM), and calibrated to historical (1980 - 1985) years for SO_2 emissions. The model is fully documented, and there is a User's Guide to its operation (report series

EPA-600/8-88-071-a through -l). All available documentation and other model reports will be published by EPA and NAPAP in the near future.

Testing has shown that AUSM is internally consistent and responds to input changes in predicted and reasonable ways. Replication of historical values is very close. Although model refinement, extension, and testing will continue, AUSM is a complete, useable tool as of this writing.

SAMPLE AUSM RESULTS

The following figures are samples of AUSM results aggregated to the national level. They are based on inputs derived from the EPA 1987 Interim Base Case and are provided only as examples. As such, they do not represent the views of EPA or AUSM's developers.

The interim base case assumes no emissions regulation beyond NSPS, RNSPS, and SIP which are already in place. Electricity demand is assumed to grow at 2.2 percent for 1986 - 1995 and 2.0 percent thereafter. Capital costs, heat rates, availability, and reliability for generating and control equipment were taken from the latest Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG) and vary by state.

Heat rates are assumed to increase at 0.25 percent/yr from the time a unit comes on line until its 30th anniversary. The interim base case further assumes that refurbishment at the 30 year point decreases the heat rate by 5 percent and degradation begins again at 0.25 percent/yr. This assumption is important because it controls economic dispatch of SIP units, many of which will be refurbished by 2000. (Importantly, no RNSPS or NSPS units will be refurbished.)

Figures 4 through 9 summarize key results. Figure 4 depicts generation by generating technology. Coal-fired RNSPS units will provide nearly all of the growth-induced generation while nuclear and oil/gas-fired units decline somewhat. Figure 5 shows capacity, with much the same trend as generation.

Figures 6 and 7 show national, energy weighted capacity factors and heat rates for coal-fired units. Both result from economic decisions made within AUSM and include cost factors such as fuel price, heat rate, O&M expense, and transmission and distribution losses.

RNSPS capacity factors are higher until the end of the period because of their lower heat rates and O&M expense. The assumed refurbishment of SIP units plus the fact that emissions controls are not required for many units makes them economically more attractive toward the end of the simulation. NSPS units fall somewhere in between, with somewhat lower heat rates than SIP units but high cost due to either low sulfur coal use or scrubber expense. Importantly, the order of capacity factors is consistent with the order of heat rates, validating AUSM results to a large extent.

Figures 8 and 9 forecast SO_2 and NO_x emissions in metric tons (tonnes) by component. Unsurprisingly, coal-fired SIP units are the largest contributors.

The results shown in Figures 4 through 9 are national aggregations. AUSM has a

FIGURE 4

GENERATION BY TECHNOLOGY

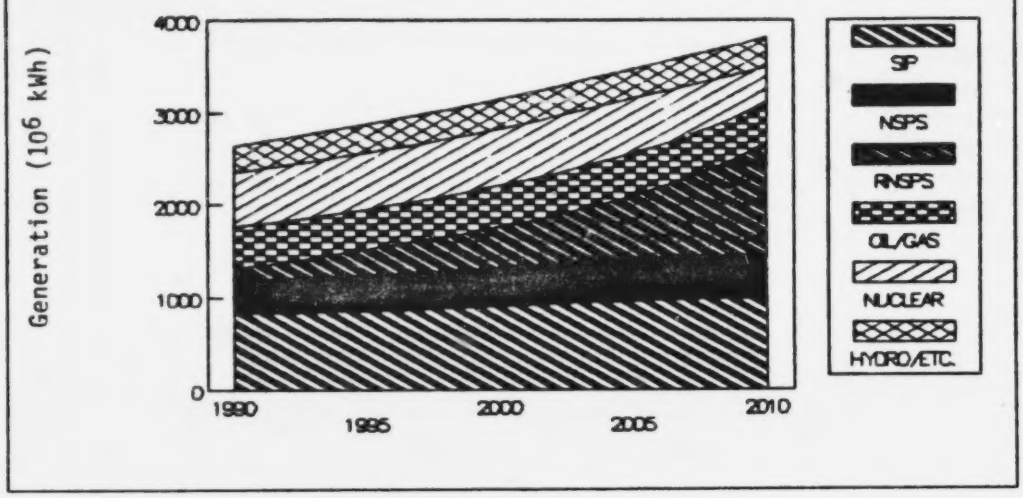


FIGURE 5

CAPACITY BY TECHNOLOGY

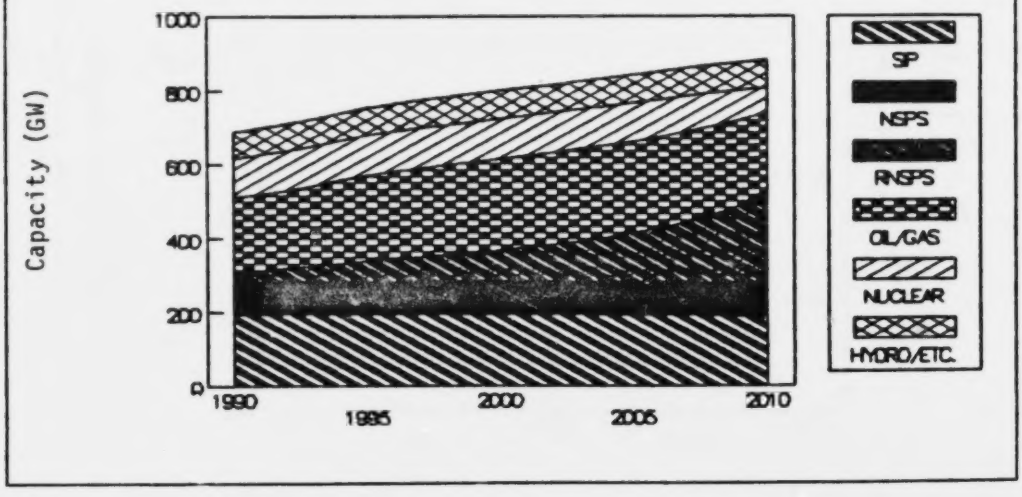


FIGURE 6

ENERGY WEIGHTED CAPACITY FACTORS

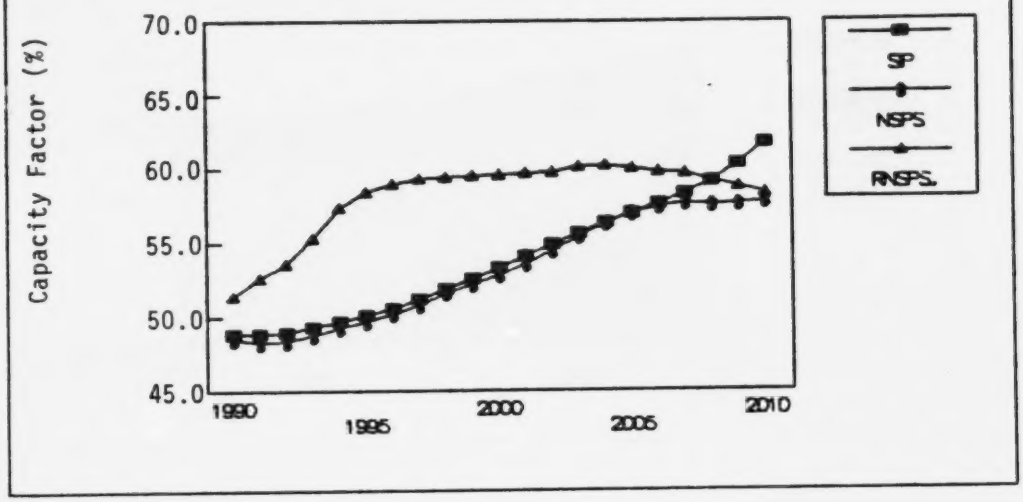


FIGURE 7

ENERGY WEIGHTED HEAT RATES

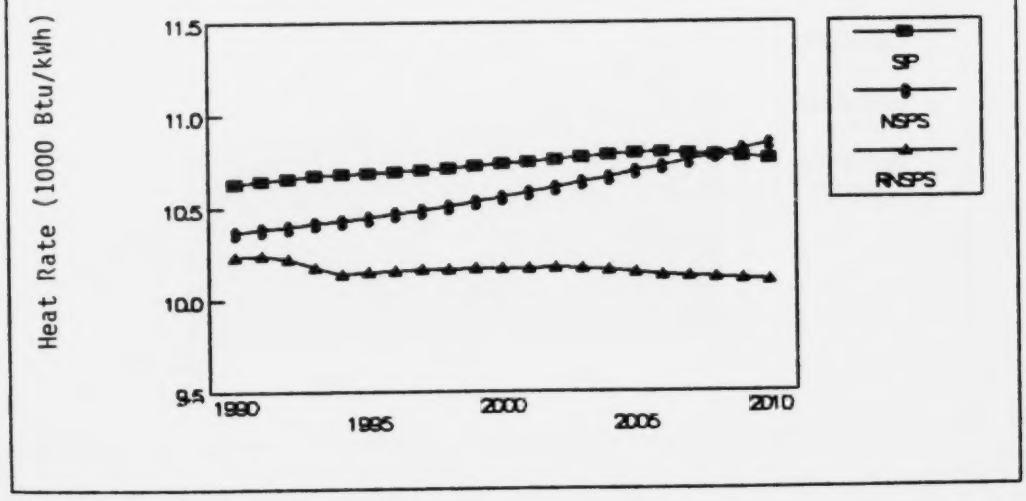


FIGURE 8

SO2 EMISSIONS BY SOURCE

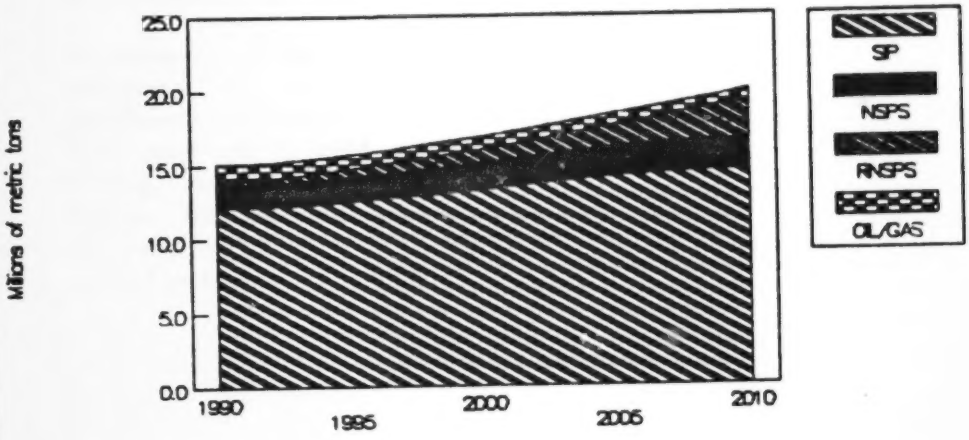
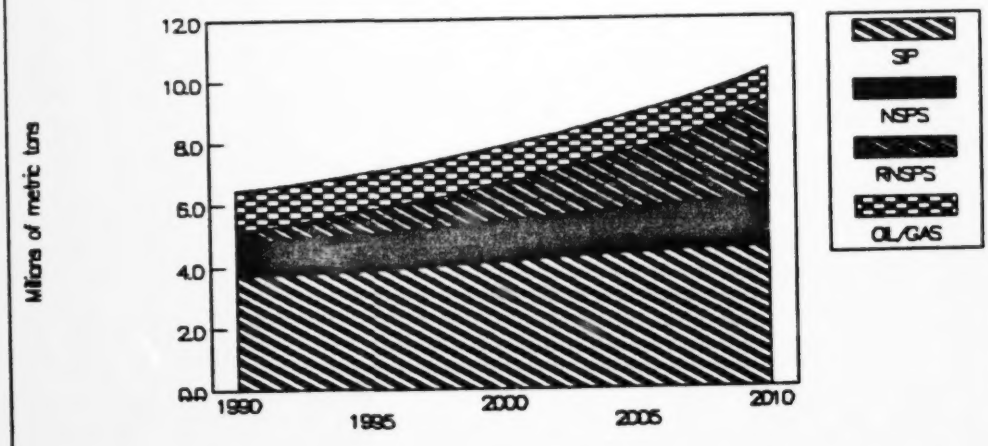


FIGURE 9

NOX EMISSIONS BY SOURCE



data base capability allowing ad hoc data aggregations based on engineering attributes of individual units, geographic factors, fuel, or any other factor tracked by the model.

In summary, AUSM's development is complete and the model outputs consistent, reasonable results. It has been subjected to third party review, testing, and comparison with other models. EPA currently plans to release the model as a publicly owned, well documented tool in the near future.